ORIGINAL

0000000796

BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

RECEIVED
2004 FEB -3 P 12: 55
AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437 **NOTICE OF FILING DIRECT TESTIMONY AND EXHIBITS OF KEVIN C. HIGGINS**

Arizona Corporation Commission
DOCKETED
FEB 0 3 2004
DOCKETED BY CN

Arizonans for Electric Choice & Competition hereby provides notice of filing the direct testimony and exhibits of its witness, Kevin C. Higgins, in the above-captioned docket.

RESPECTFULLY SUBMITTED this 3rd day of February, 2004.

FENNEMORE CRAIG, P.C.

By [signature]
C. Webb Crockett
3003 North Central Avenue
Suite 2600
Phoenix, AZ 85012
Attorneys for Arizonans for Electric Choice & Competition

The **ORIGINAL** and **13 copies** of
the foregoing were filed this
February 3, 2004, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPY of the foregoing **hand-delivered**
this February 3, 2004, to:

MARC SPITZER, Chairman
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

WILLIAM A. MUNDELL, Commissioner
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

JEFF HATCH-MILLER, Commissioner
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

MIKE GLEASON, Commissioner
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

KRISTIN K. MAYES, Commissioner
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ernest Johnson, Director of Utilities
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Christopher Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing
MAILED/*E-MAILED
this February 3, 2004, to:

Thomas L. Mumaw
Karilee S. Ramaley
PINNACLE WEST
CAPITAL CORP.
Law Department
P.O. Box 53999, MS 8695
Phoenix, Arizona 85072
*Thomas.Mumaw@pinnaclewest.com
*Karilee.Ramaley@pinnaclewest.com

Jana Van Ness
Barbara Klemstine
ARIZONA PUBLIC
SERVICE COMPANY
P.O. Box 53999
Mail Station 9905
Phoenix, Arizona 85072-3999
*jana.vanness@aps.com
*BarbaraKlemstine@aps.com

Jeffrey B. Guldner
Teresa Voss
Snell & Wilmer LLP
400 East Van Buren Street
Phoenix, Arizona 85004
*jguldner@swlaw.com
*tvoss@swlaw.com
Attorneys for Arizona Public Service Company

Major Allen G. Erickson
AFCES A/ULT
139 Barnes Drive
Suite 1
Tyndall AFB, Florida 32403-5319
*allen.cerickson@tyndall.af.mil
Attorney for Federal Executive Agencies

Rebecca C. Salisbury
56^{th} Fighter Wing JA
7383 N. Litchfield Road
Luke AFB, Arizona 85309-1540
*RSalisburyAZ@aol.com
Attorney for Federal Executive Agencies

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East 7^{th} Street
Suite 2110
Cincinnati, Ohio 45202
*mkurtzlaw@aol.com
Attorneys for Kroger Company

J. William Moore
Attorney at Law
1144 East Jefferson
Phoenix, Arizona 85034
*jwilliammoore@worldnet.att.net
Attorney for Kroger Company

Scott Wakefield
RUCO
1110 West Washington St.
Suite 220
Phoenix, Arizona 85007
*swakefield@azruco.com

Walter W. Meek
AUIA
2100 North Central Avenue
Suite 210
Phoenix, Arizona 85004
*meek@auia.org

Nicholas J. Enoch
Lubin & Enoch
349 North 4^{th} Avenue
Phoenix, Arizona 85003
*nicholasenoch@azbar.org
Attorneys for IBEW

Bill Murphy
Murphy Consulting
2422 East Palo Verde Drive
Phoenix, Arizona 85016
*billmurphy@cox.net
Consultant for Arizona Cogeneration Assn.

Jay L. Shapiro
Patrick J. Black
Fennemore Craig
3003 N. Central Avenue, Suite 2600
Phoenix, Arizona 85012
*jshapiro@fclaw.com
*pblack@fclaw.com
Attorneys for Panda Gila River, L.P.

Robert W. Geake
ARIZONA WATER COMPANY
P.O. Box 29006
Phoenix, Arizona 85038-9006
bgeake@azwater.com

Andrew W. Bettwy
Bridget A. Branigan
SOUTHWEST GAS CORPORATION
5241 Spring Mountain Road
Las Vegas, Nevada 89150
*andy.bettwy@swgas.com

Timothy M. Hogan
Arizona Center for Law
In the Public Interest
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
*thogan@aclpi.org
Attorneys for Western Resource Advocates
and Southwest Energy Efficiency Project

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, Arizona 85704-3224
*schlegelj@aol.com

Penny Anderson
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, Colorado 80302
*penny@westernresources.org

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, Arizona 85252-1064
*azbluhill@aol.com

Marvin S. Cohen
Sacks Tierney P.A.
4250 N. Drinkwater Boulevard, Fourth Floor
Scottsdale, Arizona 85251
*MarvinCohen@SacksTierney.com
Attorneys for Intervenors Constellation NewEnergy, Inc., and Strategic Energy, LLC

Raymond S. Heyman
Laura Schoeler
Roshka, Heyman & DeWulf
400 E. Van Buren, Suite 800
Phoenix, Arizona 85004
*rheyman@rhd-law.com
Attorneys for UniSource Energy Services

Deborah R. Scott
UNISOURCE ENERGY SERVICES
One South Church Street, Suite 200
Tucson, Arizona 85702
*dscott@tucsonelectric.com

Cynthia Zwick
ARIZONA COMMUNITY ACTION ASSOCIATION
2627 N. 3rd Street, Suite Two
Phoenix, Arizona 85004
*czwick@azcaa.org

S. David Childers
Low & Childers, P.C.
2999 North 44th Street, Suite 250
Phoenix, Arizona 85018
*dchilders@lowchilders.com
Attorneys for Arizona Competitive Power Alliance

James M. Van Nostrand
Katherine McDowell
George M. Galloway
Stoel Rives
900 SW Fifth Avenue, Ste. 2600
Portland, Oregon 97204
*jmvannostrand@stoel.com
*kamcdowell@stoel.com
*gmgalloway@stoel.com
Attorneys for Arizona Competitive Power Alliance

Greg Patterson, Executive Director
ARIZONA COMPETITIVE POWER ALLIANCE
916 West Adams, Ste. 3
Phoenix, Arizona 85007
*gpattersonCPA@aol.com

Lawrence V. Robertson, Jr.
Munger Chadwick P.L.C.
National Bank Plaza
333 N. Wilmot, Ste. 300
Tucson, Arizona 85711
lvrobertson@mungerchadwick.com
Attorneys for Southwestern Power Group II, LLC,
Bowie Power Station, LLC and Mesquite Power, LLC

Michael A. Curtis
William P. Sullivan
Larry Udall
Martinez & Curtis, P.C.
2712 N. 7th Street
Phoenix, Arizona 85006-1090
*mcurtis401@aol.com
*wsullivan@martinezcurtis.com
*ludall@martinezcurtis.com
Attorneys for Dome Valley Energy Partners, LLC

Michael A. Curtis
Martinez & Curtis, P.C.
2712 N. 7th Street
Phoenix, Arizona 85006-1090
*mcurtis401@aol.com
Attorneys for Town of Wickenburg

Jon Poston
AARP Electric Rate Project
6733 East Dale Lane
Cave Creek, Arizona 85331
*Jon_Poston@prodigy.net

Coralette Hannon
AARP Department of State Affairs
6705 Reedy Creek Road
Charlotte, NC 28215
*channon@aarp.org

Jay I. Moyes
MOYES STOREY 3003 N. Central Avenue, #1250
Phoenix, AZ 85012
*jimoyes@lawms.com
Attorneys for PPL Sundance, LLC and
PPL Southwest Generation Holdings, LLC

Jesse A. Dillon
Attorney at Law
Two N. Ninth Street
Allentown, PA 18101
Attorney for PPL Sundance, LLC and
PPL Southwest Generation Holdings, LLC

Mary Bollington

1499109.1/23040.041

DIRECT TESTIMONY OF KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice & Competition

Docket No. E-01345A-03-0437

February 3, 2004

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition ("AECC"), a business coalition that advocates on behalf of retail electric customers, and which supports the advancement of retail electric competition. AECC is a party to the Arizona Public Service Company ("APS") Settlement Agreement that has governed APS Standard Offer rates since 1999, and established the basis for implementing the Commission's Electric Competition Rules in the APS service territory.

Q. Were you personally involved in the negotiations that resulted in the APS Settlement Agreement?

A. Yes, I was closely involved in the negotiations on behalf of AECC.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[1] the hearings on the APS and TEP settlement agreements (1999),[2] the AEPCO transition charge hearings (1999),[3] the Commission's Track A proceeding

[1] Docket No. RE-00000C-94-0165.
[2] Docket Nos. RE-00000C-94-0165, E-01345A-98-0473, E-01933A-97-0773, E-01345A-98-0471, and E-01933A-97-0772.
[3] Docket No. E-01773A-98-0470.

(2002),[4] the APS adjustment mechanism proceeding (2003),[5] and the Arizona ISA proceeding (2003).[6]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified numerous times on the subjects of electric utility rates and industry restructuring before state utility regulators in Colorado, Georgia, Indiana, Michigan, Nevada, New York, Oregon, South Carolina, Utah, Washington, and Wyoming.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to this testimony.

PHASE I: REVENUE REQUIREMENTS

Overview and conclusions – Revenue Requirements

Q. What is the purpose of your testimony in the Revenue Requirements phase of the proceeding?

A. I have been asked to evaluate the merits of APS' general rate case filing with respect to revenue requirements. I also have been asked to recommend any adjustments to the Company's proposed revenue requirements that might be necessary to ensure results that are just and reasonable. Given the wide scope of this general rate proceeding, I have concentrated my efforts on a limited number of significant issues. Absence of comment on my part regarding a particular

[4] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[5] Docket No. E-01345A-02-0403.
[6] Docket No. E-00000A-01-0630.

revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What conclusions have you reached in your analysis of APS' revenue requirements proposals?

A. (1) The Commission should reject in its entirety APS' request to reverse the so-called "$234 million write-off" the Company took in 1999. Acquiescence to this proposal would be tantamount to granting APS a gift of at least $375 million spread over 15 years. The write-off in 1999 was an accounting matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed. In a logical sense, APS' request to "reverse" the 1999 write-off is a non-sequitur, as there was never any harm from the write-off to be "undone". The Company's proposal is merely an attempt to take back a significant part of the rate reductions granted in the Settlement Agreement – a reversal that is entirely without merit. Rejecting this proposal would eliminate $33 million of the Company's $175 million rate increase request.

(2) The Commission should deny APS' request to place into rate base 1700 MW of new generating units owned by Pinnacle West Energy Company ("PWEC"). The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to ratepayers is simply not reasonable. Moreover, selecting one company's generating units for inclusion into rate base would run counter to

Arizona's efforts to encourage development of a competitive wholesale market. Rejecting this proposal would eliminate $107 million of the Company's $175 million rate increase request.

(3) The Commission should deny APS' request to include $10 million per year in rates to recover costs associated with the Company's 2002 severance program. The severance program is a non-recurring cost that will have already been recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Rejecting this proposal would eliminate $10 million of the Company's $175 million rate increase request.

My three recommended revenue adjustments are summarized in Table KCH-1 below. As the table shows, the cumulative impact of these recommendations is to lower APS' proposed revenue requirements by approximately $150 million per year.

Table KCH-1
Summary of AECC Revenue Requirement Adjustments

Adjustment	**Revenue requirement impact**
1. Deny reversal of 1999 write-off	$ (33,215,060)
2. Deny inclusion of PWEC units in rate base	$(106,648,000)
3. Deny amortization of 2002 severance costs	$ (9,960,548)
TOTAL	$(149,823,608)

Q. Are there any special factors the Commission should bear in mind with respect to the underlying framework of this rate proceeding?

A. Yes, there is one factor in particular the Commission should bear in mind. APS rates currently incorporate a very substantial regulatory asset component, representing costs that were incurred many years ago, but which were not collected from customers at the time, and instead were deferred for later recovery. In 1996, the Commission agreed to allow APS to recover these costs on an accelerated basis. They will be fully amortized by June 30, 2004. To meet this timetable, current rates recover about $120 million in regulatory asset costs per year.[7] By the start of the rate-effective period for this proceeding, this substantial regulatory asset cost burden will have been completely paid off, a fact that is recognized in the Company's filing. Therefore, the proper starting point for this rate proceeding is the very substantial rate *reduction* coming to customers because the regulatory asset burden of the past will have been eliminated. Final rates should only increase if APS' prudent costs have grown more rapidly than the underlying cost reduction associated with the elimination of the Company's historic regulatory asset balance.

Reversal of 1999 write-off

Q. What is APS' proposal regarding the treatment of the write-off the Company took in 1999 following the approval of the Settlement Agreement?

A. As described in the direct testimony of Company witnesses Steven M. Wheeler and Donald G. Robinson, APS is asking the Commission for a special increase in rate base in the net amount of $142 million in order to "reverse" a write-off the Company took in 1999 following approval of the Settlement Agreement. The net effect of this proposal would be to raise retail rates $33 million per year.

Q. What is the rationale for APS' request?

[7] See pre-filed direct testimony of Donald G. Robinson, Attachment DGR-4, p. 2 (which provides the basis for recovery of carrying charges) and Attachment DGR-5, p. 20 (which provides amortization costs).

A. In 1999, following approval of the Settlement Agreement, APS recorded a \$140 million after-tax charge to its income statement, the basis for which is addressed in my testimony below. APS depicts this charge as the "\$234 million write-off." In this proceeding, APS justifies its request for additional rate base because the Company believes it is entitled to "reverse" the write-off it took following approval of the Settlement Agreement, due to the Company's "detrimental reliance" on that agreement. The alleged detrimental reliance is related to the Commission's Track A decision in September 2002 prohibiting divestiture of APS' generating assets to PWEC.[8]

Q. What is your assessment of APS' request?

A. I recommend against adoption of APS' request in the strongest possible terms. Acquiescence to this proposal would be tantamount to granting APS a gift of at least \$375 million spread over 15 years. This cost to ratepayers would result from the amortization of the initial \$142 million net increase in rate base plus the return earned each year on the net balance, as shown in Attachment KCH-2. As a practical matter, the benefit to APS would be even greater than \$375 million, as the revenue requirements impact from the Company's proposal is greatest in the first year, and the initial-year rate impact of \$33 million would remain in place until and unless there are subsequent rate cases.

Q. Why are you so strongly opposed to the Company's proposal?

A. I was closely involved in the negotiations that led to the Settlement Agreement in 1999 and I am very familiar with the terms of that agreement, including the basis for the write-off. The write-off in 1999 was an accounting

[8] Pre-filed direct testimony of Steven M. Wheeler, p. 4, lines 7-12.

matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed.[9] Nor was the write-off related in any way to the rate reductions granted to Standard Offer customers as a result of the Settlement Agreement. Simply put, the write-off did not result in any reduction in revenues recovered by APS from its customers. To "reverse" the write-off today would be to commit an act that has no logical basis.

Q. If the write-off had no impact on revenues from retail ratepayers, why was it taken?

A. In 1998 and 1999, APS was projecting stranded costs due to retail access in the amount of $533 million in present value terms.[10] APS' calculation represented the net revenues the Company would theoretically lose due to retail customers switching to direct access service. This "lost revenue" constituted the Company's stranded cost, which it was entitled to recover via the Competitive Transition Charge ("CTC").

The Company's stranded cost calculation, made from the perspective of 1998, assumed that *all* of APS' load would switch to direct access service as soon as it was eligible to do so (e.g., 100 percent switching by 1/1/01). According to this calculation, the impact of retail access would cause the present value of the Company's revenues to decline by $533 million over the period 1999-2004. This

[9] A relatively small number of customers took direct access service in APS' territory prior to the western price spike in 2000. Theoretically, there could be some small amount of un-recovered stranded cost associated with these sales, but at most it would be on the order of two-tenths of one percent of the "$234 million reversal" APS is seeking.

[10] This calculation was filed by APS on June 4, 1999 as Schedule JED-3, attached to the direct testimony of APS witness Jack E. Davis in the APS Settlement Agreement proceeding, Docket Nos. E-01345A-98, E-

forecasted decline in revenues took into account APS' projected sales of its "freed up" generation into a competitive market. Put another way, APS calculated that its cost of providing state-regulated generation service was going to be $533 million more expensive (in present value terms) than what the Company could sell that same generation for in the competitive market. Thus, APS considered its stranded cost to be $533 million, in accordance with the "revenues lost" methodology.

This calculation was very important because the Electric Competition Rules provide for the recovery of net stranded cost. That is, for the period 1999-2004, a customer switching to direct access service has been (and continues to be) required to pay the APS Competitive Transition Charge to recover the Company's stranded costs.[11]

Certain parties to the Settlement Agreement, such as AECC, believed the $533 million stranded cost estimate was much too high, and would not agree to base the CTC on that amount. After extensive negotiations, as a compromise, the parties agreed to base the CTC on a stranded cost of $350 million (present value).

This compromise set in motion the write-off. Because APS believed its stranded cost to be $533 million, the Company was required, in compliance with financial accounting standards, to make an accounting adjustment to write off the present value of any future revenues not expected to be recovered from regulated rates. This amount was the difference between the $533 million the Company projected in stranded cost and the $350 million it would be allowed to collect

---

01345A-0773, and RE-00000C-94-0165. The calculation was originally filed by APS with the Commission on August 21, 1998.

[11] Note that for Standard Offer customers, stranded cost recovery is built into existing rates.

through the CTC. This difference had a present value of $183 million, which was the basis for the write-off.

Q. If the basis for the write-off was $183 million, why does APS refer to it as a "$234 million" write-off?

A. $183 million is a present value amount. APS elected to apply the write-off to a stream of regulatory assets that were being amortized during the 1999-2004 period. The nominal value of the regulatory assets that were "foregone" equaled $234 million.

Q. You stated that the write-off was based on future revenues not expected to be recovered from regulated rates. Wasn't that a revenue loss to APS?

A. No, as I have stated already, APS ultimately did not experience any meaningful loss of revenue related to the write-off.

Q. Why didn't APS lose any revenue?

A. Because even though APS recovered $234 million less in regulatory assets than it would have otherwise, the Company still received the same revenues it would have absent the write-off: instead of being attributed to recovery of regulatory assets, the revenues simply added to APS' profits.

To understand this point, it is important to bear in mind that the write off – an accounting action – was based on a *forecast* of future revenues that were not expected to be recovered under regulated rates due to un-recovered stranded costs, i.e., the $183 million discussed above. That forecast was based on assumptions made in 1998 by APS about the future – assumptions that turned out to be very, very wrong. As things actually turned out, APS did *not* experience any un-recovered stranded cost, and hence, did *not* experience the revenue shortfall that was the basis of the write-off.

Q. What turned out differently than expected to preclude the revenue loss from occurring?

For one thing, APS' stranded cost calculation of $533 million assumed that *all* of its retail customers – industrial, commercial, residential – moved to direct access service as soon as they legally could. Of course, this did not happen (nor was it ever remotely likely to happen). In fact, due to high wholesale prices (combined with stranded cost charges), relatively few customers have actually taken direct access service between 1999 and today. Thus, the projected revenue loss due to the less-than-full-recovery of stranded cost never actually took place.

This point is illustrated conceptually in Attachment KCH-3. In the left-hand panel, I show the basis for the write-off, which was the present value difference between APS' projected stranded cost of $533 million and the stranded cost recovery of $350 million that would have been collected under the CTC, had all of APS' retail customers switched to direct access service. Under this scenario, once 100 percent of customer load moved to direct access service on January 1, 2001, the Company's generation-related revenues would equal the market price plus the CTC, which together were expected to fall short of the Company's cost of generation under regulation (which is depicted by the uppermost curve). This $183 million shortfall is labeled "Area A" in the diagram.

In the right-hand panel, I show conceptually what actually happened. Note that, due to the nearly complete absence of direct access transactions, the

Company's actual revenues turned out to be based on its regulated Standard Offer rates – the uppermost curve in the diagram – meaning that the Company wound up recovering its regulated generation costs. Consequently, there was never a "shortfall" of $183 million in present value revenues.

The write-off took place, but the revenue shortfall that was its basis never happened. That is, even though the Settlement Agreement package obligated APS to absorb – potentially – a $183 million shortfall, the revenue loss did not materialize. <u>In hindsight, with respect to this aspect of the Settlement Agreement, APS got a better deal than it bargained for, as the Company was obligated to absorb a potential revenue shortfall of $183 million – but ultimately did not have to.</u>

Q. What else turned out differently than expected to preclude the revenue loss from occurring?

A. In retrospect, APS' stranded cost projection of $533 million turned out to be completely wrong. Rather than its regulated cost of generation being $533 million *more expensive* than the competitive market value, for much of the intervening period, APS' generation has actually been *cheaper*. As a result, APS' stranded costs actually turned out to be *negative* over the period 1999-2003. This outcome is illustrated in Attachment KCH-4.[12] In hindsight, then, even the compromise stranded cost amount of $350 million turned out to be much too high.

[12] The calculation in Attachment KCH-4 uses the original generation cost forecast employed by APS in calculating the $533 million stranded cost figure, but updates the 1998 forecast prices with actual Palo Verde prices. Arguably, APS' own generation costs may have also increased since the 1998 forecast, but comparable cost data was not available from the Company for the years in question. Given APS' resource mix, it is extremely unlikely that higher APS fuel costs would have resulted in positive stranded cost calculation, considering the *negative* $1.4 billion present value that results from the figures in Attachment KCH-4.

As a result, even if customers *had* taken significant advantage of retail access service, APS' revenue loss due to un-recovered stranded cost would have been significantly less than the write-off, or even negligible.

There is a significant irony here. If, in 1999, APS' stranded cost calculation had been less aggressive – and, in hindsight, more accurate – the Company would not have been required to take a write-off in the first place. For instance, had APS projected stranded costs of $350 million, no write-off would have been needed, as that amount was assured recovery through the CTC even if 100 percent of customers switched to direct access. Indeed, given the fact that customers have overwhelmingly remained on Standard Offer service, APS' revenues would have turned out to be the same irrespective of whether the Company projected stranded costs of $533 million or $350 million: the only difference was whether a write-off was required.

Q. Are you advocating for some type of retroactive adjustment to stranded cost?

A. No, I am not. AECC agreed to a fixed-charge CTC in 1999, and has never sought to undo the terms of that deal, despite the obvious changes in market prices from prior expectations. But neither is APS entitled to a retroactive negation of the rate reductions in the Settlement Agreement through the "write-off reversal" claim it is pursuing in this proceeding. APS should not be rewarded now for having over-estimated stranded cost in 1998 – particularly since the write-off it incurred as a result of that over-estimation did not result in any actual reductions in APS revenues between 1999 and the present time.

Q. Does APS acknowledge that the 1999 write-off was based on projections of stranded costs?

A. Yes, but APS tries to downplay this connection. I assume this because the facts pertaining to stranded cost recovery are entirely unsupportive of APS' claim to have the write-off reversed. So, despite acknowledging stranded cost as the *basis* of the 1999 write-off, Mr. Wheeler nevertheless asserts that the *restoration* of the write-off has "nothing to do" with stranded cost.[13]

In my opinion, there is a serious disconnection here. In a logical sense, APS' request to "reverse" the 1999 write-off is a non-sequitur. Indeed, there was never any harm from the write-off to be "undone". The "reversal" story is merely a vehicle that APS is apparently employing to seek compensation from customers for unrelated damages that APS believes it has incurred due to the Commission's Track A decision prohibiting divestiture of APS' generating assets to PWEC. The problem with this story, though, is that APS tries to give the impression that the write-off in 1999 actually cost the Company money – when in fact, it did not.

Q. On page 19 of his pre-filed direct testimony Mr. Wheeler states that "if APS had not written off this $234 million, it would have continued to recover that amount in rates during the years 1999 through 2004." Is that a correct statement?

A. In a narrow sense it is correct, but it is also misleading, because it gives the impression that because of the write-off, the $234 million was somehow not recovered. APS does not point out that it is *equally true* to state:

[13] Pre-filed direct testimony of Steven M. Wheeler, 19, lines 9-13.

> Although it had written off this $234 million, APS continued to recover that amount in rates during the years 1999 through 2004.

A more complete version of Mr. Wheeler's assertion would read as follows:

Because almost all customers remained on Standard Offer service, APS would have recovered the $234 million in rates during the years 1999 through 2004 <u>*with or without*</u> *the write-off.*

Q. Was the write-off related to the rate reductions for Standard Offer customers that were implemented as part of the Settlement Agreement?

A. No. As I stated above, the write-off was solely related to stranded cost, which had nothing to do with the rate reductions to Standard Offer customers. All other things equal, reducing regulated rates for bundled customers lowers a utility's return; it does *not* cause a write-off.

Q. Do you believe it would be appropriate for APS to "take back" any part of the rate reductions that customers experienced from 1999-2004?

A. Absolutely not. Mr. Wheeler even states that it is not APS' intent to take back the rate decreases it agreed to as part of the 1999 settlement.[14] However, in defending the Company's proposal for a "reversal" of the write-off, APS states that the Company would not have agreed to the write-off *or the rate reductions* in the settlement, but for the other terms of the agreement, including divestiture.[15] <u>So, in a very real sense, APS' proposal does amount to an attempt to "take back" part of the prior rate reductions.</u> The Company did not receive the benefit of

[14] Pre-filed direct testimony of Steven M. Wheeler., p. 21, lines 5-6.

divestiture in the Settlement Agreement, and as compensation, it seeks an artificial increase in rates of $33 million per year. This is equivalent to a 1.8 percent rate increase – and it would result in higher rates for 15 years.

Q. Do you believe APS is entitled to any consideration with respect to the change in the divestiture provision in the 1999 settlement?

A. I am not opposed to APS receiving some consideration for this change. However, "reversing" the write-off to artificially raise rates $33 million per year is not an appropriate consideration. As I pointed out above, with respect to the write-off issue, APS actually wound up with a *better deal than it bargained for* in the settlement. That is because the settlement obligated APS to absorb a potential shortfall of $183 million in stranded cost – but the shortfall never materialized. This improved position of the Company should be factored in to any assessment of the damages it may have suffered from the reversal of the divestiture provision.

Q. What about APS' contention that it would not have agreed to the rate reductions absent the divestiture provision in the settlement?

A. I am not in a position to second-guess the Company's strategic tradeoffs. However, it is important to bear in mind that the Settlement Agreement was not the sole means to effect a rate reduction. Expectations about divestiture notwithstanding, APS' Standard Offer rates were always intended to be fully regulated, and therefore were always subject to reduction through a general rate case. In my opinion, the rate reductions that emerged from the Settlement

[15] APS Response to AECC 1.2a.: "APS would not have agreed to any write-off or the resulting rate reductions but for the other promises made in the Settlement, including divestiture."

Agreement were not unfair to the Company and should not be "undone" going forward to compensate APS for the change in the divestiture provision.

Q. What is the basis for your conclusion?

A. A review of the Company's earnings from 1999 through 2002 shows that APS has posted very solid returns despite the rate reductions. The Company's returns-on-equity for these years are shown in Table KCH-2 below. Indeed, in 2000, APS' return-on-equity was nearly 15 percent. While I certainly give credit to APS management for producing these returns in the face of rate reductions, it is simply not credible for the Company to insinuate that, for the purpose of advancing its "write-off reversal" argument, the rates that have prevailed since the Settlement Agreement have been in any way unjust and unreasonable to the utility. By extension, it is equally incredible to argue that those prior rate reductions should be "taken back" in this proceeding *for any reason.*

Table KCH-2
APS Return on Equity
1999-2002 [16]

1999	13.5%
2000	14.9%
2001	13.1%
2002	9.2%

Q. What consideration ought to be granted to APS in light of the reversal of the divestiture provision?

A. Section 2.6 of the Settlement Agreement establishes the basis for the Competition Rules Compliance Charge ("CRCC"), which is intended to recover costs associated with compliance with the Electric Competition Rules. In approving the Settlement Agreement, the Commission limited APS to recovery of 67 percent of the reasonable and prudent costs associated with effecting divestiture of its generation.[17] Given that APS was not permitted to implement that divestiture, I agree with APS that it should be allowed to recover 100 percent of the reasonable and prudent divestiture-related costs contemplated by Section 2.6. This higher level of cost recovery is already included in the CRCC proposed by APS, and represents about $3 million of the total CRCC spread over five years.

Rate basing of PWEC units

Q. What is APS' proposal with respect to the rate-basing of certain PWEC units?

A. APS is proposing to place five new generating units currently owned by PWEC into rate base as part of this proceeding. The units in question are Red Hawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro CT Unit 3, which have an aggregate nameplate rating of approximately 1700 MW. APS' proposal would result in a net increase in rate base of $895 million,[18] which as shown in Attachment KCH-5, would raise rates $107 million per year. As such, this proposal represents over 60 percent of the $175 million rate increase being proposed by APS in this proceeding.

Q. What is APS' rationale for this proposal?

A. APS devotes a considerable amount of direct testimony to defending this proposal. The Company's argument, at its essence, is two-pronged: (1) that rate-

[16] Moody's Analysis of APS, June 2003, p. 7 [Provided in APS Response to Utilitech 1-14.]
[17] ACC Decision No. 61973, p. 10, lines 2-8.
[18] Pre-filed direct testimony of Donald G. Robinson, p. 11, lines 20-21.

basing these units is a fair reward to Pinnacle West for having invested in Arizona generation during a critical time, and (2) that it is in ratepayers' long-term interests for these plants to be in rate base, where they will be priced at cost-of-service, and shielded from market volatility.

Q. What is your assessment of the Company's proposal?

A. The Company's proposal to rate base the PWEC units should not be adopted. The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to rate payers is simply not reasonable. Moreover, Arizona has had a substantial amount of merchant generation constructed since the adoption of the Electric Competition Rules in 1996, with over 8800 MW added since 2001 (including PWEC). Selecting one company's generating units for inclusion into rate base would run counter to Arizona's efforts to encourage development of a competitive wholesale market.

Q. Is there any circumstance in which any of the PWEC generation should be considered for rate base treatment?

A. The only exception to excluding all of the PWEC generation from rate base treatment is the special case of generation constructed inside the Phoenix load pocket, to the extent that such generation is needed to meet load that cannot be served from competitive generation. In my opinion, that would leave open the door to possible *future* rate base treatment of some portion of the West Phoenix units. However, as those units were constructed at-risk and are currently under contract through 2006, I do not believe it is appropriate to include them in rate base at this time.

Q. Please address APS' argument that rate basing the PWEC units is a fair reward for having invested in Arizona generation.

A. When the Commission approved the 1998 version of the Electric Competition Rules it was abundantly clear that any new generation constructed in Arizona (other than by SRP) would be built "at risk." That is, there was absolutely no presumption that new generation would enter rate base. Indeed, the opposite was the case, as the Affected Utilities were required to divest the generation they had.

Consequently, when PWEC began construction of Red Hawk, West Phoenix 4 and 5, and Saguaro CT Unit 3, some *two years after* the adoption of the 1998 Rules, there could be no mistake on the part of Pinnacle West management that these units were being constructed in the full light of market risk and return. Indeed, under the Electric Competition Rules, there was not even assurance that APS would be obliged to purchase even a single megawatt-hour from these units.

Q. What about the Commission's reversal of the divestiture requirement? Doesn't that change the situation of these units?

A. No. When the Commission reversed the divestiture requirement as part of the Track A Order in September 2002, it changed the future treatment of APS' existing fleet of units: rather than being divested into the competitive generation market, those units will remain in APS rate base. But the PWEC units were never intended for rate base. Thus, their status as at-risk units has not been changed at all.

Q. **Do you believe that Arizona has benefited from the construction of the PWEC facilities?**

A. I have no reason to doubt that the construction of these units has been a benefit to Arizona. The best indication is that these units are supplying power to APS pursuant to the Track B solicitation. In my opinion, it is essential that these units continue to supply power to APS under their current contracts, at prices that were bid at arm's length. That way, customers continue to receive the benefit of competitively bid generation as envisioned by the Commission in establishing the Track B process.

Q. **Do you believe that it is in ratepayers' interest that the PWEC units be brought into rate base now, in order to protect against future market volatility?**

A. No, I do not. APS' "rate base proposal" for hedging against future market volatility is an expensive deal for customers. The $107 million incremental annual cost relative to purchasing the requisite power pursuant to the Track B solicitation is simply too hefty, and should be rejected.

Q. **How should APS acquire the additional power needed to serve its Standard Offer customers after the Track B contract with PWEC expires?**

A. Consistent with the Commission's Procedural Order on January 8, 2003, APS has sought competitive bids for the needed generation, including the 1700 MW now being provided by PWEC under contract. According to APS, these bids are currently being evaluated. To the extent that the results of the solicitation demonstrate that there will be a shortfall in delivering power to the Phoenix load pocket after 2006, it would be reasonable to consider rate base treatment for that portion of the West Phoenix generation needed to serve the load pocket. In my opinion, such rate base treatment, to the extent warranted, should not start before 2007, and should only be reflected in rates in the context of a future rate case.

Responses to questions posed by Commissioner Gleason

Q. Are you familiar with the questions raised by Commissioner Gleason relating to the rate basing of merchant generation in his letter of September 5, 2003?

A. Yes, I am. Commissioner Gleason has asked parties to respond to questions concerning the determination of market value for power plants, the presence of other power plants on the market that could serve Arizona, precedence in other jurisdictions for incorporating merchant assets into rate base, and the impact on the Track B process from including the PWEC assets into rate base.

Q. Do you have any comments you wish to make in response to these questions?

A. Yes. Commissioner Gleason's inquiry into market valuation speaks to the question of whether net book value (i.e., original cost net of depreciation and accumulated deferred income taxes) or market value should be used as the basis for additions to rate base, in the that event APS' proposal to place PWEC assets into rate base is approved in whole or part.

While, as I have discussed above, I am opposed to bringing any of the PWEC assets into rate base at this time, I believe Commissioner Gleason's question is an important inquiry to the extent that APS' proposal is considered. Ultimately, the question boils down to the Commission's assessment of what is just and reasonable. If the Commission is inclined to allow a merchant plant into rate base, it would not be unreasonable for the Commission to consider whether the plant's book value exceeded its market value, and to deny inclusion in rate base of any portion that was excess. If the Company felt the results of such an approach was unacceptable, it could withdraw its application.

Unfortunately, the mechanics of such an assessment of market value would be problematic, and would likely require an assessment by asset valuation experts, who would consider such factors as discounted net cash flow, cost-of-capital, and net salvage value in making a determination. Such an analysis would be needed because the assets are owned by an affiliate and any asset transfer would not be presumed to occur at an arm's length price.

In the case of generation constructed in the Phoenix load pocket, net book value can be given more weight, in my opinion. I have had a long involvement in addressing load pocket issues in Arizona, both in the Arizona ISA process, as well as in RTO negotiations, and am of the view that load pocket generation must be subject to price regulation during periods of import constraint. One of the guidelines to use in such regulation is cost-of-service. It is essential, however, that to the extent that any consideration is given to including the West Phoenix units into rate base, a condition of such approval be that the output of those units be made available at cost-of-service prices to competitive ESPs to serve any ESP retail load in the load pocket during periods of import constraint. Such a condition would be equivalent to requiring the generating units to be subject to the Arizona ISA Local Generation Requirement protocol, or any successor protocol adopted by an RTO.

Q. Turning to another of Commissioner Gleason's questions, are you personally familiar with instances in other jurisdictions in which merchant generation has been brought into rate base?

A. In one recent case in which I am familiar, PSI Energy, a vertically-integrated utility located in Indiana, purchased the 700 MW Madison and Henry County Generating Stations from subsidiaries of Cinergy, which is an affiliated company. PSI Energy then requested inclusion of those units in rate base based on the purchase price. It is my understanding that the transfer took place pursuant to the terms of a contested settlement agreement between PSI Energy, Indiana regulatory staff, and the Indiana utility consumer advocate office that was ultimately approved by the Indiana Utility Regulatory Commission. The transfer price was based on the net book value of the plant, with some adjustments. Apparently, in that instance, the Indiana Commission determined that net book value was a reasonable measure of the facilities' worth.

Q. Are you aware of any other power plants in Arizona that are available to be purchased at this time?

A. I am not personally aware of any specific power plants that are for sale in Arizona at the current time.

Q. What would be the likely impact on the Track B process from including the PWEC assets in rate base?

A. Adopting the Company's proposal to put the PWEC assets into rate base would undermine the Track B process. At the most fundamental level, it would replace power that was contracted through the Track B process and replace it with rate base generation (from the same power plants) that is significantly more expensive. Moreover, rate basing the 1700 MW of PWEC generation in question would short-circuit the Track B bidding process for this amount of contestable load in the future. As I recommended above, with respect to the Track B process, APS should be required to purchase power from the PWEC units under their current contracts, at prices that were bid at arm's length. For the period following the expiration of these contracts, APS should be required to continue the Track B process by seeking competitive bids for its contestable load, including the 1700 MW now being provided by PWEC. If the results of the solicitation demonstrate that there will be a shortfall in delivering power to the Phoenix load pocket after 2006, as APS claims will happen, then it would be appropriate to consider alternative approaches, including rate basing some portion of the West Phoenix generation after the current PWEC contract expires.

Q. Do you have any other issues you would like to bring to the attention of the Commission regarding APS' proposal to place the PWEC units in rate base?

A. Yes. I am concerned that the introduction of PWEC units could give rise to a future generation of stranded cost claims by APS. Militating against this possibility is the fact that the Electric Competition Rules make it clear that resources added after 1996 are not eligible for stranded cost recovery. Moreover, AECC entered into the 1999 Settlement Agreement with the expectation that the matter of stranded cost would be resolved permanently. In the event that the Commission gives consideration to APS' rate base proposal, I recommend that a condition of any rate base treatment be the exclusion of the PWEC resources from any future charges to recover alleged stranded cost.

Employee severance costs

Q. What has APS proposed with respect to severance costs?

A. In 2002, Pinnacle West offered an employee severance package that cost $36 million, some $30 million of which is allocated to APS. According to the Pinnacle West 2002 Annual Report, the severance program lowered Pinnacle West's labor costs by $30 million per year. Embedded in APS' proposed rates is a three-year amortization of APS' share of the cost of this severance program, which would cost ratepayers about $10 million per year.

Q. What is your assessment of the Company's proposal regarding severance costs?

A. It is not appropriate for customers in 2004-06 to pay for the cost of this severance program, which was enacted in 2002. The severance program is a non-recurring cost that will have already been fully recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Therefore, the severance costs should be excluded entirely from the revenue requirements of the rate-effective period.

Q. But won't customers benefit from the labor cost savings?

A. Yes, but APS shareholders will have already benefited handsomely first, because the initial benefit of the cost-savings from the severance program has been accruing to them. The severance program was enacted in 2002 during a period when retail rates had already been established pursuant to the 1999 Settlement Agreement. Consequently, the full benefit of the cost savings in the second half 2002, all of 2003, and the first six months of 2004 will have accrued solely to APS shareholders. As Pinnacle West has reported the savings to be $30 million per year, and as APS represents five-sixths of the program costs, some $25 million per year in APS labor cost savings are currently accruing to APS shareholders from this program. Just counting 2003 and the first half of 2004, the APS-related savings will have exceeded $37 million, completely recovering the APS-related costs, leaving over $7 million in net benefits to shareholders. There is no reason to now turn around and bill ratepayers $30 million over the next three years to recover the severance program's costs. The costs will have already been more than recovered. Therefore, I recommend that the Company's revenue requirements be reduced by the $10 million annual cost of amortizing the 2002 severance program.

Conclusion – Revenue Requirements

Q. Would you please summarize the main points in your revenue requirements testimony?

A. (1) The Commission should reject in its entirety APS' request to reverse the so-called "$234 million write-off" the Company took in 1999. The write-off in 1999 was an accounting matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed. The Company's proposal is merely an attempt to take back a significant part of the rate reductions granted in the Settlement Agreement – a reversal that is entirely without merit. Rejecting this proposal would eliminate $33 million of the Company's $175 million rate increase request.

(2) The Commission should deny APS' request to place into rate base 1700 MW of new generating units owned by Pinnacle West Energy Company ("PWEC"). The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to rate payers is simply not reasonable. Moreover, selecting one company's generating units for inclusion into rate base would run counter to Arizona's efforts to encourage development of a competitive wholesale market. Rejecting this proposal would eliminate $107 million of the Company's $175 million rate increase request.

(3) The Commission should deny APS' request to include $10 million per year in rates to recover costs associated with the Company's 2002 severance program. The severance program is a non-recurring cost that will have already been recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Rejecting this proposal would eliminate $10 million of the Company's $175 million rate increase request.

PHASE II: COST-OF-SERVICE, RATE SPREAD, RATE DESIGN

<u>Overview and conclusions – Cost-of-Service, Rate Spread, and Rate Design</u>

Q. What is the purpose of your testimony in the Cost-of-Service, Rate Spread, and Rate Design phase of the proceeding?

A. I have been asked to evaluate the merits of APS' general rate case filing with respect to cost-of-service, rate spread, and rate design. I also have been asked to recommend any adjustments to the Company's proposed treatment of these subjects that might be necessary to ensure results that are just and reasonable.

Q. What conclusions have you reached in your analysis of APS' treatment of cost-of-service, rate spread, and rate design?

A. (1) APS' use of the 4-CP method for allocating fixed production cost is appropriate given its system load characteristics and should be accepted by the Commission.

(2) APS' proposal to differentiate General Service rates by voltage levels is consistent with the general approach adopted in the vast majority of utility tariffs across the country and should be approved by the Commission.

(3) APS' proposal to present its rates in an unbundled format is consistent with the requirements of the Electric Competition Rules, provides better information to customers, and should be adopted.

(4) APS' cost-of-service analysis demonstrates that General Service customers are *currently* paying rates that exceed the Company's revenue requirements even after the Company's proposed $166 million base rate increase is factored in. That is, on a strict cost-of-service basis, no rate increase is warranted for this customer class. Consequently, the Company's proposed across-the board increase is not

reasonable. Instead, any rate increase should be spread in such a way the percentage increase to General Service customers is 60 percent of the system average percentage increase. In the event that rates are decreased, the decrease should be spread in such a way that the percentage decrease to General Service customers is 125 percent of the system average percentage decrease.

(5) I agree with APS' attempt to simplify the design of Rate E-32. However, *within* the E-32 customer group, the Company's proposed rate increase falls more heavily on medium-sized customers (e.g., 500 kw demand) than is appropriate. This outcome should be modified by reallocating any rate increase within the E-32 customer group such that relatively less of the increase is spread to medium-sized customers, and relatively more of it is spread to the large-sized customers (1500 kw to 3000 kw demand).

(6) APS proposes to charge transmission voltage customers an unbundled distribution charge. Transmission voltage customers should not be charged an unbundled distribution charge, as these customers do not use the distribution system. In the current tariff, the only cost in the unbundled distribution charge is the recovery of pre-1999 regulatory assets, which will be completed by June 30, 2004. Exhibit A, Schedule B of the Settlement Agreement explicitly states that transmission voltage customers will not pay distribution costs after June 30, 2004. Consistent with this provision, the APS distribution charge for transmission voltage customers should be removed from APS' proposed rates.

(7) APS' proposal to change the definition of on-peak hours for Rate E-35 should be rejected. Current E-35 customers have adapted their business operations to meet

the terms of the existing definitions in the tariff. Changing the definitions will be disruptive and potentially costly to major businesses that have planned their operations in reliance on the tariff's existing definitions.

Use of the 4-CP method for allocating fixed production costs

Q. Why do you agree with the Company's use of the 4-CP method for allocating fixed production costs?

A. APS' system demands are driven by summer usage. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, thereby properly aligning cost allocation with cost causation. Given APS' system load characteristics, the 4-CP method is inherently reasonable.

Differentiation of General Service rates by voltage level

Q. Why do you agree with the Company's proposal to differentiate General Service rates by voltage level?

A. Commercial and industrial customers typically take service at one of three basic voltage levels: secondary, primary, or transmission. The cost of providing service differs according to voltage level; for instance, line losses are significantly lower for transmission service than for secondary service. Yet currently, APS' Standard Offer General Service rates do not distinguish among service at differing voltage levels (although the Company's Direct Access rates do make such a distinction). Failure to set different rates for different voltage levels causes a subsidy within the General Service class from higher-voltage customers to lower-voltage customers.

In my experience, I know of no other utility that does not differentiate its rates across secondary, primary, and transmission service. APS' proposal to make such a distinction in this proceeding is consistent with the general approach adopted in the vast majority of utility tariffs across the country and should be approved by the Commission.

<u>Unbundling of rate components</u>

Q. Why do you agree with the Company's proposal to present its rates in an unbundled format?

A. Separating individual rate components by function, such as generation, transmission, and distribution, is required by the Electric Competition Rules. The Company's proposal to separately identify these rate components rates conforms to the requirements of the Rules, and will provide better information to customers. In separately stating generation and transmission cost components, it will make the process of evaluating direct access opportunities more transparent for customers who wish to do so. The Company's proposal on this issue should be adopted.

<u>Rate spread</u>

Q. Why do you disagree with the Company's proposal to spread its proposed rate increase on an across-the-board equal percentage basis?

A. As reproduced in Table KCH-3, below, APS' cost-of-service analysis shows that at *current* rates, General Service customers are providing a 9.00 percent return on rate base to the Company, which is even higher than the return the Company is requesting in this proceeding. In other words, on a strict cost-of-service basis, *none* of the Company's claim of a $166 million base rate shortfall is attributable to General Service customers. General Service rates are sufficiently high now to enable APS to more-than-fully recover its claimed costs plus requested return from these customers.

Table KCH-3
APS Return by Customer Class
At Current Rates [19]

Residential	4.34%
General Service	9.00%
Irrigation	0.63%
Street Lighting	2.48%
Dusk-to-Dawn	3.08%
Total Retail	6.27%

In such a situation, an across-the-board percentage increase applied to General Service customers is not equitable.

Q. What rate spread do you propose instead of the Company's approach?

A. Although a straight across-the-board approach is not equitable, AECC members recognize that, if the Company's $166 million base rate increase were adopted, adhering to a rate spread based strictly on cost-of-service results would lead to significantly higher rate increases for residential customers. Therefore, I am proposing a modification to the Company's rate spread that would limit any rate increase to General Service customers to 60 percent of the system average increase. This approach would move the rate spread *in the direction* of cost-of-service results, while still significantly mitigating the impact of the Company's rate increase on residential customers. The results of this rate spread are presented

[19] APS Schedule G-1.

in Attachment KCH-6 and are summarized in Table KCH-4 below, for the case in which the Company's $166 million base rate increase is adopted. Table KCH-5 compares rate spreads for the case in which my recommended $150 million reduction to the Company's revenue requirement is adopted.

Table KCH-4
Summary of Rate Spread Results
if APS $166 million base rate increase is adopted

Customer class	Strict COS	Equal %	AECC
Residential	19.04%	9.31%	12.93%
General Service	(1.10)%	9.31%	5.59%
Irrigation	28.94%	9.34%	12.93%
Street Lighting	43.30%	9.31%	12.93%
Dusk-to-Dawn	35.75%	9.31%	12.93%
Total Retail	9.31%	9.31%	9.31%

Table KCH-5
Summary of Rate Spread Results
if APS $166 million base rate increase is reduced by $150 million

Customer class	Equal %	AECC
Residential	0.95%	1.32%
General Service	0.95%	0.57%
Irrigation	0.95%	1.32%
Street Lighting	0.95%	1.32%
Dusk-to-Dawn	0.95%	1.32%
Total Retail	0.95%	0.95%

Q. What do you recommend in the event that APS base rates are reduced?

A. If APS base rates are reduced, the decrease should be spread in such a way that the percentage decrease to General Service customers is 125 percent of the system average percentage decrease. Such a spread would move rates in the direction of cost-of-service, as General Service rates are currently providing disproportionately high returns relative to other customer classes.

Rate design for Rate E-32

Q. What are your concerns regarding the Company's proposal for Rate E-32?

A. APS is proposing to simplify the design of Rate E-32, which in its current form, is extremely complex and difficult for customers to understand. I fully support APS' intentions in this regard.

However, in spreading its proposed rate increase across E-32 customers, the Company's approach creates inequities among E-32 customers that need to be rectified. Specifically, an inordinate share of the Company's proposed 9.7 percent increase for this sub-class falls on medium-sized customers, i.e., those with billing demands around 500 kw. This can be seen by examining APS Schedule A-4, the results of which are partially reproduced in Table KCH-6 below.

Table KCH-6
Impact of Proposed Rates on Selected E-32 customers
if APS $175 million rate increase is adopted

kw	load factor	summer increase	winter increase
100	30%	19.5%	20.8%
100	60%	-4.5%	-7.5%
100	75%	-9.8%	-13.9%
500	30%	26.3%	27.6%
500	60%	17.5%	13.8%
500	75%	15.0%	9.9%
3000	30%	23.0%	22.6%
3000	60%	14.7%	9.6%
3000	75%	12.5%	6.0%

As shown in Table KCH-6, at each load factor, a customer with a 500 kw demand would experience a significantly-higher rate impact than either smaller or larger customers. This outcome is particularly inappropriate as the Company's own analysis shows that customers of this size (100 kw to 999 kw) are already recovering their costs more fully than customers in the 1000 kw to 3000 kw range.[20]

Q. What do you recommend to rectify this problem with the proposed E-32 rate?

A. The Company's proposed E-32 rate has two demand blocks in the distribution charge. The first block applies to the first 500 kw of demand and is proposed to be priced at $6.348/kw-mo. for secondary service. The second block is proposed to be priced at $4.618/kw-mo. for all kw over 500 kw for secondary service. The problem with sizing the first demand block at 500 kw is that it exacerbates the plight of customers around 500-kw in size – contributing to the inequity of their outcome relative to both smaller and larger customers.

This problem can be rectified by sizing the first demand block at a smaller kw, such as 100 kw. (100 kw is convenient because APS has filed billing determinant data that corresponds to this break-point.) Note that APS' proposed rate design will actually *reduce* rates for 100 kw customers with load factors greater than 60 percent. If we raise the price of the first block ten percent to $7.00/kw-mo., but start the second block at 100 kw, the resultant "revenue-neutral" price of the second block would be $5.054 per kw-mo. for secondary service. This calculation is shown in Attachment KCH-7. Relative to APS' proposal, this alternative would lessen the rate decrease for customers with 100

[20] Pre-filed direct testimony of Alan Propper, Attachment AP-3, shows the Medium General Service class (100 kw – 1000 kw) is currently producing a return of 8.88% and the Large General Service class (1000 kw – 3000 kw) is producing a return of 3.28 %.

kw demands. It would improve the outcome for customers in the range of 200 kw to 1200 kw, have little impact on customers in the range of 1200 kw to 1500 kw, and result in a slightly higher rates for the larger customers in the E-32 class. These outcomes are consistent with APS' cost-of-service results. The impact is summarized in Table KCH-7, below, which can be compared with Table KCH-6, which shows the results under APS' proposal.

Table KCH-7
Impact of Alternative Rate Design on Selected E-32 customers if APS $175 million rate increase is adopted

kw	load factor	summer increase	winter increase
100	30%	22.6%	24.3%
100	60%	-2.7%	-5.5%
100	75%	-8.3%	-12.2%
500	30%	21.6%	22.4%
500	60%	14.4%	10.3%
500	75%	12.3%	6.9%
3000	30%	24.2%	24.0%
3000	60%	14.2%	9.3%
3000	75%	12.1%	5.8%

Q. What is your recommendation to the Commission on this issue?

A. The Commission should order APS to change the break-point for the first demand block in the E-32 rate from 500 kw to 100 kw. The blocks should then be re-priced as described in my testimony and in accordance with the methodology shown in Attachment KCH-7. To the extent that the revenue requirement as it pertains to distribution service for E-32 customers is ultimately modified in this proceeding, the final price for the E-32 demand blocks would be scaled down (or up) accordingly.

<u>Distribution charge for transmission voltage service</u>

Q. Why do you object to APS' proposal to charge a distribution charge to transmission voltage customers?

A. Transmission voltage customers should not be charged an unbundled distribution charge, as these customers do not use the distribution system. In the current tariff, the only cost in the unbundled distribution charge is the recovery of pre-1999 regulatory assets, which will be completed by June 30, 2004. Exhibit A, Schedule B of the Settlement Agreement explicitly states that transmission voltage customers will not pay distribution costs after June 30, 2004. (I negotiated that language with APS as part of the Settlement Agreement.) Consistent with this provision, the APS distribution charge for transmission voltage customers should be removed from APS' proposed rates. Instead, these costs should be recovered from the customers who use the primary and secondary distribution systems.

Q. How can that be accomplished?

A. As a practical matter, this can be readily accomplished in either one of two ways. (1) To the extent that APS' proposed revenue requirement is reduced as part of this proceeding, the first dollars of the reduction that would go to transmission voltage customers could be earmarked for eliminating the distribution charge; or (2) To the extent that the rate spread is modified (as I have proposed above), the first dollars of the reduction from APS' proposal that would go to transmission voltage customers could be earmarked for eliminating the distribution charge for those customers.

<u>Definition of on-peak hours for Rate E-35</u>

Q. Why do you disagree with APS' proposal to change the definition of on-peak hours for Rate E-35?

A. Rate E-35 provides time-of-use pricing for customers with loads greater than 3000 kw. APS is proposing to change the definition of on-peak hours, such that the on-peak period would begin two hours earlier each week day, i.e., starting at 9 a.m. instead of 11 a.m. (The on-peak period would continue to end at 9 p.m. each week day.) The problem with this proposal is that current E-35 customers have adapted their business operations to meet the terms of the existing definitions in the tariff. Changing the definitions will be disruptive and potentially costly to major businesses that have planned their operations in reliance on the tariff's existing definitions.

For example, I have discussed this situation with representatives of Honeywell, which is a Rate E-35 customer at its Laboratory Services test site in Phoenix. Honeywell moved to Rate E-35 in 1998 at APS' urging, as a means of reducing its peak demand via load management. Because of the price signals sent by the E-35 rate, Honeywell has moved much of its testing to the overnight shift, reducing its peak demand from 17.1 MW to an average of 8.3 MW. Accomplishing this change required a significant effort in reshaping corporate culture, as it requires the most manpower and energy-intensive products to be operating on an overnight basis. Since the change to E-35, Honeywell has continued to install additional equipment and automated controls to minimize its on-peak usage in reliance on the terms of the E-35 tariff.

Honeywell plans its most energy-intensive operations such that they end just before 11 a.m. each day. Changing the definition of on-peak hours to start at 9 a.m. will completely disrupt the work schedules that Honeywell has developed in reliance on the current definition, and will cause Honeywell to seriously consider abandoning the time-of-use rate, as its benefits may be negated by the change.

Q. What is your recommendation to the Commission regarding APS' proposed change in the definition of on-peak hours?

A. The proposed change in definition should be rejected. One of the unintended consequences of the proposed change is the disruption to the operations of customers who moved to this rate in good faith and have made human and capital investments in reliance on its existing terms.

Q. Does this conclude your direct testimony?

A. Yes, it does.

1508451.1/23040.041

KEVIN C. HIGGINS
Principal, Energy Strategies, L.L.C.
39 Market St., Suite 200, Salt Lake City, UT 84101
(801) 355-4365

Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (Track A proceeding) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 1400-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"Questar Pipeline Company," **Federal Energy Regulatory Commission**, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," **Arizona** Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to present.

Participant, Michigan Stranded Cost Collaborative, March 2003 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

1508454.1/23040.041

Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

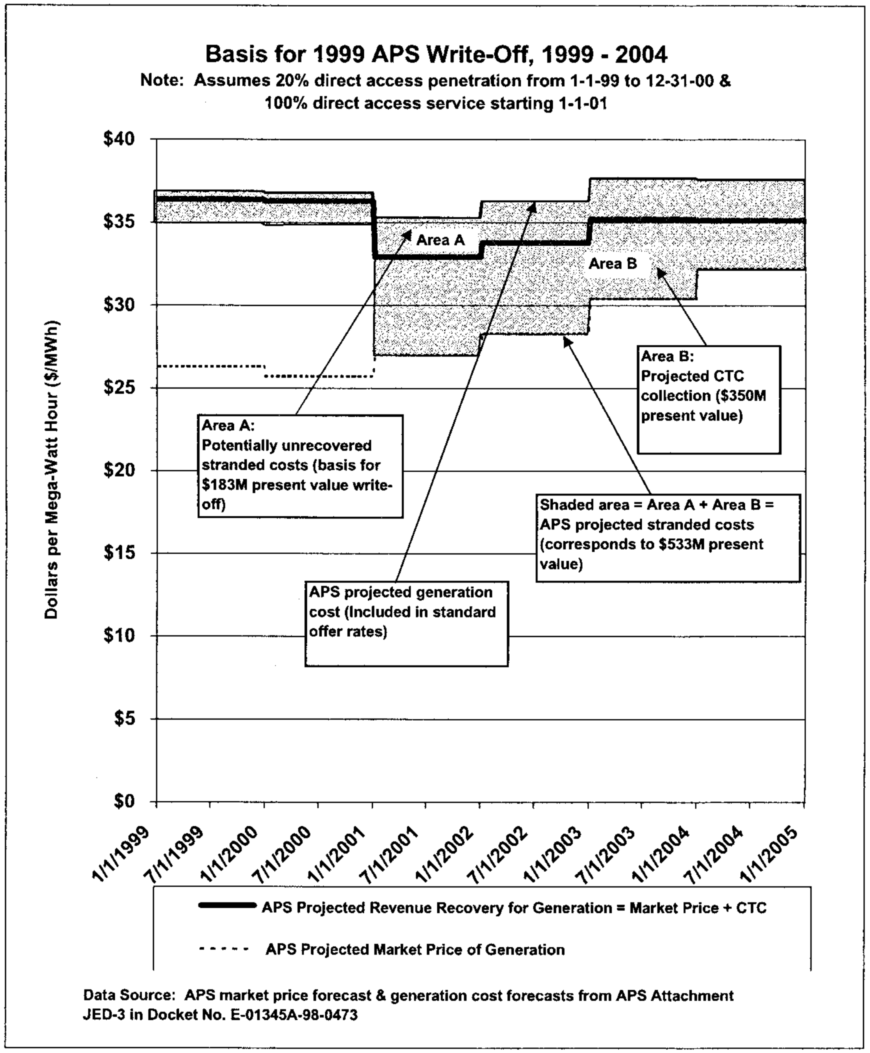
Ln #		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	Rate Base Impacts:						
1	Rate Base Additions:						
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 234,000	$ 218,400	$ 202,800	$ 187,200	$ 171,600	$ 156,000
3	Rate Base Deductions:						
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 92,430	$ 86,268	$ 80,106	$ 73,944	$ 67,782	$ 61,620
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162
6	Total Rate Base ($000s)	$ 141,570	$ 132,132	$ 122,694	$ 113,256	$ 103,818	$ 94,380
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%	8.67%
8	Required Return on Rate Base ($000s)	$ 12,274	$ 11,456	$ 10,638	$ 9,819	$ 9,001	$ 8,183
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%	39.50%
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289
11	Revenue Gross Up for Tax Impact ($000s)	$ 20,288	$ 18,935	$ 17,583	$ 16,230	$ 14,878	$ 13,525
	Operating Expense Adjustment (Assuming 15 Year Amortization of Write-Off):						
12	Depreciation & Amortization Expense ($000s)	$ -	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600
13	Interest Impact:						
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%
15	Debt Ratio	50%	50%	50%	50%	50%	50%
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%	2.89%
17	Interest Expense ($000s):	$ -	$ 4,094	$ 3,821	$ 3,548	$ 3,275	$ 3,002
18	Effective Tax Rate (%)	39.50%	39.5%	39.5%	39.5%	39.5%	39.5%
19	Amortization Income Tax Impact ($000s)	$ -	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)
20	Interest Expense Income Tax Impact ($000s)	$ -	$ (1,617)	$ (1,509)	$ (1,401)	$ (1,294)	$ (1,186)
21	Income Tax Impact ($000s)	$ -	$ (7,779)	$ (7,671)	$ (7,563)	$ (7,456)	$ (7,348)
22	Operating Income After Tax	$ -	$ 7,821	$ 7,929	$ 8,037	$ 8,144	$ 8,252
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289
24	Income Grossed Up for Taxes ($000s)	$ -	$ 12,927	$ 13,105	$ 13,284	$ 13,462	$ 13,640
	Total Rev. Req't Impact:						
25	Return on Rate Base Component ($000s)	$ 20,288	$ 18,935	$ 17,583	$ 16,230	$ 14,878	$ 13,525
26	Amortization Expense Impact ($000s)	$ -	$ 12,927	$ 13,105	$ 13,284	$ 13,462	$ 13,640
27	Total Rev. Req't Impact ($000s)	$ 20,288	$ 31,863	$ 30,688	$ 29,514	$ 28,340	$ 27,165

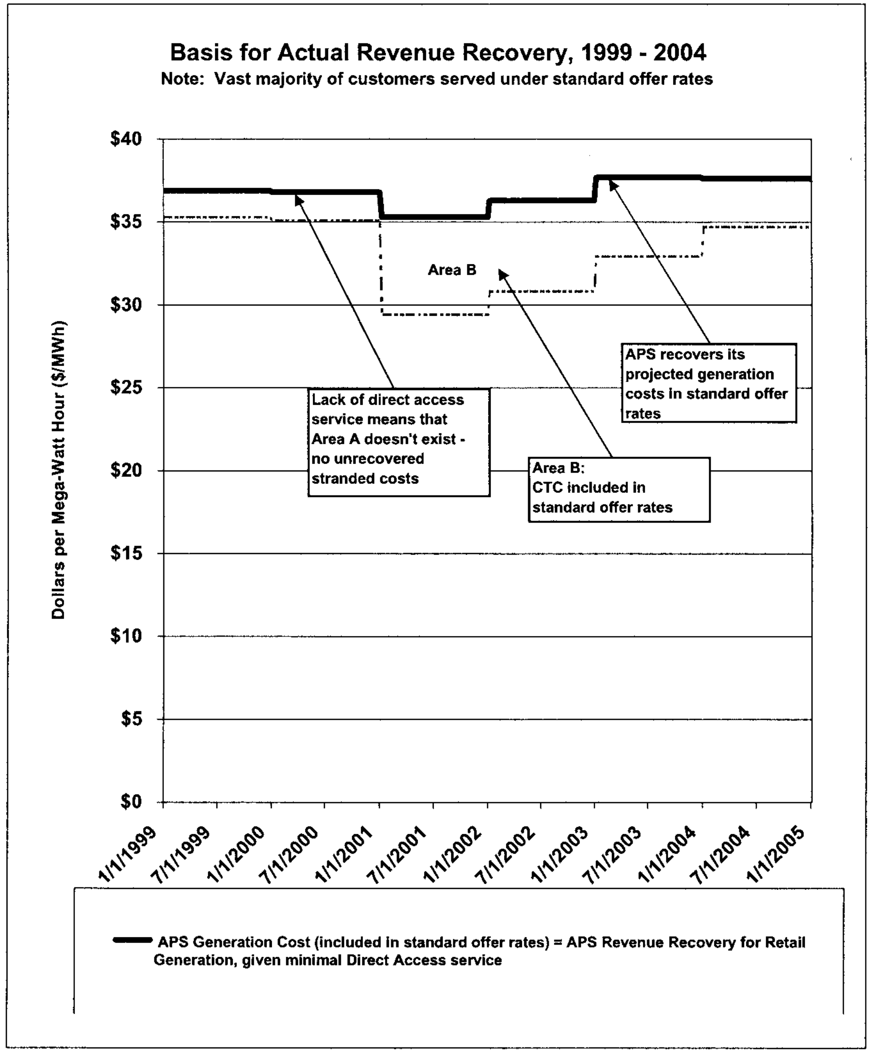
Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

Ln #		Year 6	Year 7	Year 8	Year 9	Year 10
	Rate Base Impacts:					
1	Rate Base Additions:					
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 140,400	$ 124,800	$ 109,200	$ 93,600	$ 78,000
3	Rate Base Deductions:					
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 55,458	$ 49,296	$ 43,134	$ 36,972	$ 30,810
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162
6	Total Rate Base ($000s)	$ 84,942	$ 75,504	$ 66,066	$ 56,628	$ 47,190
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%
8	Required Return on Rate Base ($000s)	$ 7,364	$ 6,546	$ 5,728	$ 4,910	$ 4,091
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289
11	Revenue Gross Up for Tax Impact ($000s)	$ 12,173	$ 10,820	$ 9,468	$ 8,115	$ 6,763
	Operating Expense Adjustment (Assuming 15 Year Amortization of					
12	Depreciation & Amortization Expense ($000s)	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600
13	Interest Impact:					
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%
15	Debt Ratio	50%	50%	50%	50%	50%
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%
17	Interest Expense ($000s):	$ 2,729	$ 2,456	$ 2,183	$ 1,910	$ 1,637
18	Effective Tax Rate (%)	39.5%	39.5%	39.5%	39.5%	39.5%
19	Amortization Income Tax Impact ($000s)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)
20	Interest Expense Income Tax Impact ($000s)	$ (1,078)	$ (970)	$ (862)	$ (755)	$ (647)
21	Income Tax Impact ($000s)	$ (7,240)	$ (7,132)	$ (7,024)	$ (6,917)	$ (6,809)
22	Operating Income After Tax	$ 8,360	$ 8,468	$ 8,576	$ 8,683	$ 8,791
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289
24	Income Grossed Up for Taxes ($000s)	$ 13,818	$ 13,996	$ 14,175	$ 14,353	$ 14,531
	Total Rev. Req't Impact:					
25	Return on Rate Base Component ($000s)	$ 12,173	$ 10,820	$ 9,468	$ 8,115	$ 6,763
26	Amortization Expense Impact ($000s)	$ 13,818	$ 13,996	$ 14,175	$ 14,353	$ 14,531
27	Total Rev. Req't Impact ($000s)	$ 25,991	$ 24,817	$ 23,642	$ 22,468	$ 21,294

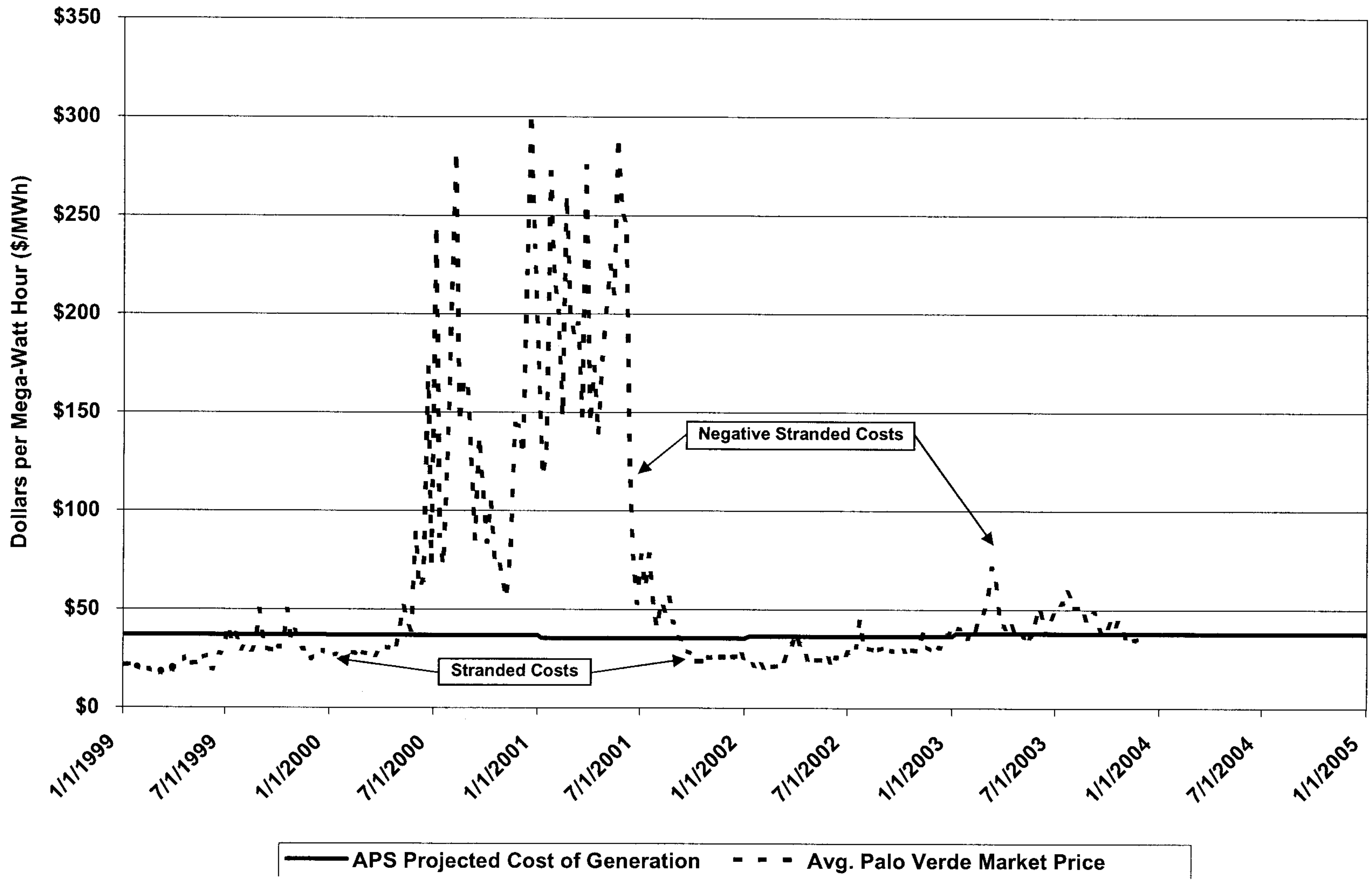
Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

Ln #		Year 11	Year 12	Year 13	Year 14	Year 15	Total	Source
	Rate Base Impacts:							
1	Rate Base Additions:							
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 62,400	$ 46,800	$ 31,200	$ 15,600	$ -		APS Data Response Attachment RC02337
3	Rate Base Deductions:							
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 24,648	$ 18,486	$ 12,324	$ 6,162	$ -		APS Data Response Attachment RC02337
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162			$92.4M ÷ 15 years
6	Total Rate Base ($000s)	$ 37,752	$ 28,314	$ 18,876	$ 9,438	$ -		Ln 2 - Ln 4
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%		APS Data Response Attachment RC02337
8	Required Return on Rate Base ($000s)	$ 3,273	$ 2,455	$ 1,637	$ 818	$ -		Ln 6 x Ln 7
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%		SFR_SCH_C3
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289		SFR_SCH_C3
11	Revenue Gross Up for Tax Impact ($000s)	$ 5,410	$ 4,058	$ 2,705	$ 1,353	$ -	$ 162,302	Ln 8 x Ln 10
	Operating Expense Adjustment (Assuming 15 Year Amortization of							
12	Depreciation & Amortization Expense ($000s)	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 234,000	$234M ÷ 15 years
13	Interest Impact:							
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	APS Data Response Attachment RC02337
15	Debt Ratio	50%	50%	50%	50%	50%	50%	APS Data Response Attachment RC02337
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%	2.89%	APS Data Response Attachment RC02337
17	Interest Expense ($000s):	$ 1,365	$ 1,092	$ 819	$ 546	$ 273		Ln $6_{(yr-1)}$ x Ln 16
18	Effective Tax Rate (%)	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	= Ln 9
19	Amortization Income Tax Impact ($000s)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (92,430)	Ln 12 x Ln 18
20	Interest Expense Income Tax Impact ($000s)	$ (539)	$ (431)	$ (323)	$ (216)	$ (108)	$ -	Ln 17 x Ln 18
21	Income Tax Impact ($000s)	$ (6,701)	$ (6,593)	$ (6,485)	$ (6,378)	$ (6,270)	$ (92,430)	Ln 19 + Ln 20
22	Operating Income After Tax	$ 8,899	$ 9,007	$ 9,115	$ 9,222	$ 9,330	$ 141,570	Ln 12 + Ln 20
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289	= Ln 10
24	Income Grossed Up for Taxes ($000s)	$ 14,709	$ 14,887	$ 15,065	$ 15,244	$ 15,422	$ 234,000	Ln 22 x Ln 23
	Total Rev. Req't Impact:							
25	Return on Rate Base Component ($000s)	$ 5,410	$ 4,058	$ 2,705	$ 1,353	$ -	$ 162,302	= Ln 11
26	Amortization Expense Impact ($000s)	$ 14,709	$ 14,887	$ 15,065	$ 15,244	$ 15,422	$ 212,618	= Ln 24
27	Total Rev. Req't Impact ($000s)	$ 20,119	$ 18,945	$ 17,770	$ 16,596	$ 15,422	$ 374,920	Ln 25 + Ln 26


Basis for 1999 APS Write-Off, 1999 - 2004
Note: Assumes 20% direct access penetration from 1-1-99 to 12-31-00 & 100% direct access service starting 1-1-01
Dollars per Mega-Watt Hour ($/MWh)
$40
$35
$30
$25
$20
$15
$10
$5
$0
1/1/1999
7/1/1999
1/1/2000
7/1/2000
1/1/2001
7/1/2001
1/1/2002
7/1/2002
1/1/2003
7/1/2003
1/1/2004
7/1/2004
1/1/2005
Area A
Area B
Area A: Potentially unrecovered stranded costs (basis for $183M present value write-off)
APS projected generation cost (Included in standard offer rates)
Area B: Projected CTC collection ($350M present value)
Shaded area = Area A + Area B = APS projected stranded costs (corresponds to $533M present value)
APS Projected Revenue Recovery for Generation = Market Price + CTC
APS Projected Market Price of Generation
Data Source: APS market price forecast & generation cost forecasts from APS Attachment JED-3 in Docket No. E-01345A-98-0473


Basis for Actual Revenue Recovery, 1999 - 2004
Note: Vast majority of customers served under standard offer rates
Dollars per Mega-Watt Hour ($/MWh)
$40
$35
$30
$25
$20
$15
$10
$5
$0
1/1/1999
7/1/1999
1/1/2000
7/1/2000
1/1/2001
7/1/2001
1/1/2002
7/1/2002
1/1/2003
7/1/2003
1/1/2004
7/1/2004
1/1/2005
Area B
Lack of direct access service means that Area A doesn't exist - no unrecovered stranded costs
Area B: CTC included in standard offer rates
APS recovers its projected generation costs in standard offer rates
APS Generation Cost (included in standard offer rates) = APS Revenue Recovery for Retail Generation, given minimal Direct Access service

APS' Actual Stranded Cost 1999 - 2003



Stranded Cost Calculation 1999 - 2003

Year	Energy Production (GWh)	APS Generation Costs (¢/kWh)	Palo Verde Avg Market Price (¢/kWh)	% Eligible for Shopping	Stranded Costs ($ Millions)	1999 NPV @ 8.8% ($ Millions)
1999	23,152	3.69	2.71	20%	45	42
2000	23,652	3.68	9.36	20%	-269	-227
2001	24,571	3.53	10.70	100%	-1,761	-1,367
2002	23,374	3.63	2.83	100%	186	133
2003	23,374	3.77	4.40	100%	-148	-97
Total					-1,946	-1,517
ACC Jurisdictional @ 93.5%					-1,820	-1,418

Palo Verde Market Price: Annual average of published weekly weighted index price at Palo Verde

Calculation Methodology: Same as APS original $533 million calculation (Attachment JED-3 in Docket No. E-01345A-98-0473), except actual market prices used instead of 1998 APS market price forecast.

Rate Impact of Including PWEC Assets in Rate Base

Ln #		Amount	Source
	Rate Base Impact:		
1	Total Rate Base - ACC Jurisdiction ($000s)	$ 889,237	Schedule B-2, p. 1 of 3
2	APS Requested Return on Rate Base for 12/31/02	8.67%	Schedule D1
3	Required Return on Rate Base	$ 77,097	Ln 1 x Ln 2
	Operating Income Impact:		
4	Change in Operating Income	$ 12,575	Schedule C-2, p. 3 of 10
	Overall Revenue Requirement Impact:		
5	Total Required Revenue Change	$ 64,522	Ln 3 - Ln 4
6	Revenue Conversion Factor	1.6529	Schedule C-3
7	Total Annual Revenue Requirement Impact	$ 106,648	Ln 5 x Ln 6

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - Present Rates
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
(As filed by APS)
($000)

					Total ACC Jurisdiction				
Ln #		Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Residential (D)	General Service (E)	Irrigation (F)	Street Lighting (G)	Dusk to Dawn (H)
1.a	Revenues by Rates	1,827,189	1,791,584	35,605	889,898	883,595	2,099	10,794	5,198
1.b	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132	36,432	839,733	730,686	2,360	12,439	4,914
3.	Operating Income Before Income Taxes	351,613	350,014	1,598	121,352	227,158	(46)	937	613
4.	Income Taxes	86,608	86,144	463	18,616	67,806	(75)	(195)	(7)
5.	Net Operating Income	265,005	263,870	1,135	102,736	159,352	29	1,132	620
6.	Rate Base	4,221,019	4,207,476	13,543	2,367,112	1,769,998	4,571	45,676	20,118
7.	Rate of Return	6.28%	6.27%	8.38%	4.34%	9.00%	0.63%	2.48%	3.08%

Data Source: APS Schedule G-1, Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PROPOSED RATES USING APS PROPOSED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED
(As Filed by APS)

		Base Revenues in the Test Year		APS Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	972,747	82,849	9.31%	3,717	9.73%
2	General Service	883,595	965,868	82,273	9.31%	4,485	9.82%
3	Irrigation	2,099	2,295	196	9.34%	11	9.86%
4	Outdoor Lighting	10,794	11,799	1,005	9.31%	36	9.64%
5	Dusk to Dawn Lighting Service	5,198	5,682	484	9.31%	14	9.58%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - Class Revenues Adjusted by AECC to Match Overall APS Requested ACC Jurisdiction Rate of Return
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

					Total ACC Jurisdiction				
Ln #		Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Residential (D)	General Service (E)	Irrigation (F)	Street Lighting (G)	Dusk to Dawn (H)
1.a	Revenues by Rates	1,993,995	1,958,390	35,605	1,059,308	873,853	2,706	15,468	7,056
1.b	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,564	1,590,132	36,432	839,733	730,686	2,360	12,439	4,914
3.	Operating Income Before Income Taxes	518,418	516,820	1,598	290,762	217,416	561	5,611	2,471
4.	Interest Expense	NA	131,928	NA	74,222	55,500	143	1,432	631
5.	Income Taxes	152,495	152,032	463	85,533	63,957	165	1,650	727
6.	Net Operating Income	365,923	364,788	1,135	205,229	153,459	396	3,960	1,744
7.	Rate Base	4,221,019	4,207,476	13,543	2,367,112	1,769,998	4,571	45,676	20,118
8	Rate of Return	8.67%	8.67%	8.38%	8.67%	8.67%	8.67%	8.67%	8.67%

Data Source: APS Schedule G-1, Page 1 of 1 modified such that class return matches APS requested ACC jurisdiction return

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
COST-OF-SERVICE BASED RATES USING APS PROPOSED INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	1,059,308	169,410	19.04%	3,717	19.45%
2	General Service	883,595	873,853	(9,742)	-1.10%	4,485	-0.59%
3	Irrigation	2,099	2,706	607	28.94%	11	29.47%
4	Outdoor Lighting	10,794	15,468	4,674	43.30%	36	43.63%
5	Dusk to Dawn Lighting Service	5,198	7,056	1,858	35.75%	14	36.02%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,390	166,806	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1 as modified in Attachment KCH-6, p. 3 to match strict cost of service results

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
AECC PROPOSED RATES USING APS PROPOSED INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	APS Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	1,005,004	115,106	12.93%	3,717	13.35%
2	General Service @ 60% of Overall %	883,595	932,956	49,361	5.59%	4,485	6.09%
3	Irrigation	2,099	2,371	272	12.93%	11	13.46%
4	Outdoor Lighting	10,794	12,190	1,396	12.93%	36	13.27%
5	Dusk to Dawn Lighting Service	5,198	5,870	672	12.93%	14	13.20%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1 modified to limit General Service class to 60% of overall retail percentage increase

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
EQUAL PERCENTAGE RATE INCREASE USING AECC REVENUE ADJUSTMENTS TO APS REQUESTED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	AECC Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	898,334	8,436	0.95%	3,717	1.37%
2	General Service	883,595	891,971	8,376	0.95%	4,485	1.46%
3	Irrigation	2,099	2,119	20	0.95%	11	1.47%
4	Outdoor Lighting	10,794	10,896	102	0.95%	36	1.28%
5	Dusk to Dawn Lighting Service	5,198	5,247	49	0.95%	14	1.22%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,808,567	16,983	0.95%	8,263	1.41%

Data Source: APS Schedule H-1, Page 1 of 1 modified to spread AECC proposed revenue increase on equal percentage basis

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
AECC PROPOSED RATES USING AECC REVENUE ADJUSTMENTS TO APS REQUESTED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	AECC Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	901,617	11,719	1.32%	3,717	1.73%
2	General Service @ 60% of Overall %	883,595	888,621	5,026	0.57%	4,485	1.08%
3	Irrigation	2,099	2,127	28	1.32%	11	1.84%
4	Outdoor Lighting	10,794	10,936	142	1.32%	36	1.65%
5	Dusk to Dawn Lighting Service	5,198	5,266	68	1.32%	14	1.59%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,808,567	16,983	0.95%	8,263	1.41%

Data Source: APS Schedule H-1, Page 1 of 1 modified to spread AECC proposed revenue increase and to limit General Service class to 60% of overall retail percentage increase

Adjustments To E-32 Rate Design

Arizona Public Service Company Adjusted 2002 Test Year E-32 Billing Determinants					
E-32, 20 < kW < 100 Small GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	3,599,159	$7.000	$25,194,113	$22,847,458	$2,346,655.00
			$25,194,113		
Summer (May-Oct)					
1st 100 kW	4,134,380	$7.000	$28,940,660	$26,245,046	$2,695,614.00
			$28,940,660		
Total E-32, 20 < kW < 100 Small GS, kW $			**$54,134,773**	**$49,092,504**	**$5,042,269**

AECC - Total E-32, 20 < kW < 100 Small GS - kW $	**$54,134,773**
APS - Total E-32, 20 < kW < 100 Small GS - kW $	**$49,092,504**
Difference	**$5,042,269**

Arizona Public Service Company Adjusted 2002 Test Year E-32 Billing Determinants					
E-32, 100 <= kW < 1000 Med GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	2,168,000	$7.000	$15,176,000	$32,506,750	($17,330,750)
over 100 kW	3,340,655	$5.054	$16,884,804	$1,791,181	$15,093,623
			$32,060,804	**$34,297,931**	**($2,237,127)**
Summer (May-Oct)					
1st 100 kW	2,682,200	$7.000	$18,775,400	$40,704,220	($21,928,820)
over 100 kW	4,229,774	$5.054	$21,378,714	$2,308,265	$19,070,449
			$40,154,114	**$43,012,485**	**($2,858,371)**
Total E-32, 100 <= kW < 1000 Med GS, kW $			**$72,214,918**	**$77,310,416**	**($5,095,498)**

E-32, kW > 1000 Lg GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	87,800	$7.000	$614,600	$2,667,567	($2,052,967)
over 100 kW	1,244,613	$5.054	$6,290,697	$4,212,496	$2,078,201
			$6,905,297	**$6,880,063**	**$25,234**
E-32, kW > 1000 Lg GS					
Summer (May-Oct)					
1st 100 kW	106,200	$7.000	$743,400	$3,320,353	($2,576,953)
over 100 kW	1,558,214	$5.054	$7,875,742	$5,270,794	$2,604,948
			$8,619,142	**$8,591,147**	**$27,995**
Total E-32, kW > 1000 Lg GS kW $			**$15,524,439**	**$15,471,210**	**$53,229**

AECC - Total Med GS and Lg GS - kW $	**$87,739,357**
APS - Total Med GS and Lg GS - kW $	**$92,781,626**
Difference	**($5,042,269)**

AECC - Total Sm, Med, Lg - kW $	**$141,874,130**
APS - Total Sm, Med, Lg - kW $	**$141,874,130**
Difference	**$0**